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ENERGY AND ENVIRONMENTAL ANALYSIS, INCORPORATED,
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16. ABSTRACT

This report is the seventh volume in support of the Inflation Impact Statement for sulfur dioxide regulations prepared by the U.S. Environmental Protection Agency, to correct deficiencies in the Ohio State Implementation Plan. The Technical Support Document, Volumes I and II may be obtained through the National Technical Information Service - EPA 905/2-76-002, PB-257 694 and PB-257 695.

This document presents the methods used for estimating costs of compliance and choice of control strategies for industry, and outlining the cost minimizing strategies which provide the basis for estimating impacts.

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Prepared for:

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Prepared by:

Energy and Environmental Analysis, Inc.
1701 North Fort Myer Drive
Suite 1213
Arlington, Virginia 22209

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SECTION I

Introduction

A. Purpose of Report

This document reports the methods used to determine the costs incurred by industries seeking to comply with SO_x regulations being considered by the U.S. Environmental Protection Agency for the state of Ohio. It is one of a series of nine background documents prepared to support the conclusions drawn in the inflationary impact statement (see Appendix A). The impacts associated with the costs determined there will be discussed in Background Document #4.

B. Background

The industry segment of stationary SO_x emitters encompasses a variety of fuel combustion and process sources. Industrial plants in Ohio contain stacks in either general category or both. The largest number of stacks (approximately 1200) are included in the fuel combustion sub-category, where fossil fuel is burned to generate steam. In this study, however, it is assumed that only those sources burning coal or oil (slightly less than 400) can potentially be out of compliance with the regulations. Those burning natural gas or coke are not considered because the low sulfur content of these fuels is not expected to violate SO_x standards.

Process sources considered in this analysis may be divided into three general types:

- Sources which emit SO_x due to the combustion of fossil fuel (67 such stacks are included in the analysis). These are primarily kilns and furnaces where fuel is used directly in providing heat to the process. As with steam generation sources, only coal and oil are considered as potential SO_x emitting fuels.

- Sources which emit SO_x due to chemical processing (6 sources are included). The only sources of this type examined were sulfuric acid plants, where elemental sulfur or in some cases, acid sludge, hydrogen sulfide, or smelter off-gas is combusted.

- Sources which omit SO_x due to the combustion of fuel gases containing hydrogen sulfide (18 plants of this nature are included. The number of stacks in this group is far higher). These sources are mostly found in steel mills (using coke oven gas) and oil refineries (using refinery off-gas).

Methods of limiting SO_x emissions differ among emitter categories. Fuel combustion sources, both process and boiler, may switch to coal or oil of lower sulfur content, or they may install desulfurization systems (FGD) to treat their exhaust gases. Chemical processes, such as sulfuric acid plants can use dual absorption systems. Hydrogen sulfide in refinery or steel mill fuel gas streams may be removed in amine scrubbers with attached Claus sulfur recovery units.

It is the purpose of this paper to describe both the engineering cost algorithms used for each of the control technologies evaluated.

C. Data Sources

Two basic types of information were needed in order to perform the industrial control cost analysis. First were a series of cost algorithms to determine from sets of plant-specific parameters, control costs for each industrial SO_x emitter in Ohio. Second were plant specific parameters, including SO_x emissions and fuel utilization characteristics needed as inputs to the cost algorithms. The following subsection describes the sources for both these sets of information.

1. Cost Algorithms

As described previously, four basic types of sources were considered in this analysis. These include fuel combustion sources (boilers), fuel combustion processes, chemical processes, and fuel gas burning processes. The algorithms used in costing each were different.

For the most part, the cost algorithms used were derived from a study performed by Batelle Columbus Laboratories.[1/] Modifications to these algorithms are described in detail in Sections II.B through II.E of this document. The cost algorithms developed were supplemented in two major respects.

Because cost calculations had not been performed for fuel combustion processes, the cost algorithms used for boilers were

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1/ Batelle Columbus Laboratories, Estimation of Costs Applying to Proposed Ohio SO_2 Regulations to Industrial Processes and Non-Utility Fuel Combustion Sources, prepared for U.S. EPA, April, 1976. See Document Number 9.

adapted for this purpose by developing several factors for each plant. These were used to determine the existing sulfur contents of fuels burned in the plants as well as annual fuel consumption from data provided on total process weight rate and emissions. More details on the approach used are described in Section II.C.

In calculating the costs of low sulfur coal substitution as a means of complying with SO_2 regulations, it was necessary to develop a coal price matrix with the prices paid in different areas of Ohio for various categories of sulfur content coals. This matrix was developed in the same manner as the matrix used in the utility cost analysis. Further details on this portion of the analysis may be found in Section II.B.2.

2. Plant Specific Data

For each type of source a series of plant specific data was needed as inputs to the cost algorithms. Boiler source data was derived from a computerized data tape. This tape and its contents are described fully in Document Number 9.

Plant specific parameters needed as inputs to the fuel gas combustion and chemical process source algorithms were obtained through telephone conversations with the staff members responsible for preparing the control cost estimates for these sources in Document Number 9.

Fuel combustion process source data was obtained from USEPA Region V. In all cases this information included emissions and total fuel and non-fuel throughput weight. Section II.C describes this information at greater length.

SECTION II

General Methodology

A. Overview

The purpose of this section is to describe the costing procedures used for each of the major categories of emission sources. Four subsections follow, covering boilers, fuel combustion process sources, chemical processes, and fuel gas burning processes (oil refineries and steel mills). No costs are determined for sulfur recovery plants or incinerators.[1/]

The cost algorithms described are for calculating capital and operating and maintenance costs. To annualize these costs the general formula below was used.[2/]

$$\text{Annual Cost} = \frac{\text{Capital Cost}}{\text{Expected Life of Equipment}} + \text{(Rate of Return on Investment)} \times \text{Capital Cost} + \text{Operating and Maintenance Cost}$$

B. Fuel Combustion Sources

Four control methods were considered for boilers. These included flue gas desulfurization (FGD), low sulfur coal, a combination of FGD and low sulfur coal, and low sulfur oil. For coal fired

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1/ Incinerators were excluded because they are not regulated by this regulation package. Sulfur recovery plants were excluded in document #9.

2/ The rate of return on investment used for the comparison of the low-sulfur coal and scrubbing options was 20 percent. This before-tax rate of return was selected, in part, on the basis of a study published in Business Horizon, October 1975 "Effective Use of Capital Budgeting Tools" by Glenn H. Petry. The number correlated well with industry responses on both after-tax and before-tax cutoff minimum investment return rates on new investments. Obviously, the cutoff will vary depending upon capital structure, riskiness of the investment, type of industry, etc.

An assumed capital structure including 35 percent debt was used in calculating the after-tax capital costs. These were used to determine price impacts and assumed that the costs passed through to the consumer would allow the company to maintain the target rate of return.

boilers all four methods were evaluated; for oil fired only FGD and low sulfur oil were costed.

1. Flue Gas Desulfurization

Formulas for retrofit FGD systems applied to non-utility boilers were obtained from Document Number 9. This document examined a double-alkali scrubbing system, which is felt to be comparable to other leading FGD systems, including lime and limestone scrubbers. The specific cost formulas were based on the experience of a Parma, Ohio General Motors plant.

For coal fired units, capital and operating and maintenance (O&M) costs formulas are shown in Table II-1. Capital costs are a function of the maximum firing rate (a surrogate for maximum exhaust gas flow). The capital scale factor (.83) is assumed to be equivalent to that of utility scrubbing systems. O&M costs are a function of average annual firing rate (a surrogate for utilities, labor, maintenance and miscellaneous costs) and coal sulfur content (a surrogate for chemicals costs). The annual coal consumption scale factor of 0.853 represents a combination of the scale factors of the individual cost components. The chemicals O&M factor of .34 is determined by examining in the Parma facility how an increase in sulfur content would affect overall O&M costs. Two sets of equations were considered applicable based on the removal required by the regulation. The first set of equations in the table is considered applicable to those cases where the required removal rate is between 60% and 80%. No by-passing of exhaust gas was considered at these levels, because the costs were felt to outweigh the savings which might be realized through a smaller sized FGD unit. The second set of equations cover the case where SO_2 removal required is less than 60%. At these levels, by-passing is considered a feasible option and thus only a fraction of the coal requiring treatment is considered.

Table II-2 presents the formulas used for calculating FGD costs for oil-fired boilers. Rather than using maximum or average firing rate as the dependent variable, the oil-fired equations were based on a maximum exhaust gas flow, i.e., the maximum volume of flue-gas produced per unit time. In all other respects, the oil-fired equations are identical to those presented in Table II-1 for coal-fired boilers.

2. Low Sulfur Coal

Another option employed by industrial fuel combustion sources is conversion to coal of sufficiently low sulfur content to comply with the regulation. Costs for this technology were estimated in a two step process.

In the first step each stack's average annual firing rate was determined by multiplying the number of hours operated per year times the average hourly firing rate. Both these pieces of information were available from the data tape.

The second step involved two parts: 1) a determination of the existing sulfur content of the coal presently burned as well as the sulfur content allowed by the regulation, and 2) calculation of the price per MMBTU differential between these levels. Because the boiler regulation is expressed in #SO_2/MMBTU, the allowable sulfur content is equivalent to the regulation. The existing sulfur content was derived by dividing the maximum emission rate (#/hr) by the maximum firing rate (MMBTU/hr). The price differential determined by comparing the price of coal of each sulfur content in a three dimensional price matrix.

Details on the derivation of the price matrix are discussed in the background document on coal prices (Background Document #10). For industries, the matrix differed slightly from that for utilities in that coal could only be bought from five of seven supply regions, and delivered to one of eleven general delivery regions, instead of 30 utility site locations. Low-sulfur

Table II-1

Cost Algorithms for

Flue-Gas Desulfurization

in Coal Fired Units

For Required Reductions Between 60% and 80%

$$\text{Capital Cost } (\$10^6) = .4153(MFR)^{.83}$$

$$\text{O\&M Cost } (\$10^6) = 28.64 \times 10^{-6}(AFR \times HRS)^{.853}(SVL)^{.34}$$

For Required Reductions Less Than 60%

$$\text{Capital Cost } (\$10^6) = .39578\left(MFR \times \frac{RED}{.8}\right)^{.83}$$

$$\text{O\&M Cost } (\$10^6) = 26.78 \times 10^{-6}\left(AFR \times HRS \times \frac{RED}{.8}\right)^{.853}(SVL)^{.34}$$

Notes:

MFR = Maximum Firing Rate (tons/hr)
AFR = Average Firing Rate (tons/hr)
HRS = Operating Hours Per Year (hours)
SVL = Sulfur Content (% S by weight)
RED = Reduction Required $\left(\frac{\text{Actual Emissions - Allowed Emissions}}{\text{Actual Emissions}}\right)$

Source: Document No. 9

Table II-2

Cost Algorithms for

Flue-Gas Desulfurization

in Oil Fired Units

For Required Reductions Between 60% and 80%

$$\text{Capital Cost}_{(\$10^6)} = 193.27 \times 10^{-6} (SA)^{.83}$$

$$\text{O\&M Cost}_{(\$10^6)} = 10.68 \times 10^{-6} (SA)^{.853} (SVL)^{.34}$$

For Required Reductions Less than 60%

$$\text{Capital Cost}_{(\$10^6)} = 184.13 \times 10^{-6} \left(\frac{RED}{.8} \times SA \right)^{.83}$$

$$\text{O\&M Cost}_{(\$10^6)} = 10.0 \times 10^{-6} \left(\frac{RED}{.8} \times SA \right)^{.853} (SVL)^{.34}$$

Notes:

SA = Air Flow to Stack (CFM)

SVL = Sulfur Content (% S by weight)

RED = Reduction Required $\left(\frac{\text{Actual Emissions - Allowed Emission}}{\text{Actual Emissions}} \right)$

Source: Document No. 9.

coal from the West (Utah, Colorado, and the Northern Great Plains) was not considered available to Ohio industries because of the excessively high cost of shipping such coal in less than unit train volumes, the present lack of adequate wholesale dealer distribution set-ups for marketing Western coal to numerous small non-utility installations, and the boiler energy derates when they switch to Western coal.

Selection of the regions was based on population distribution, proximity to coal production regions, the distribution of coal consumption, and the availability of transportation. More specifically, the distribution of rail tariffs from Pennsylvania, Ohio, West Virginia, and Eastern Kentucky were plotted on an overlay map of Ohio. Region boundaries were assigned to minimize the variation of transportation costs from all these origins within a region. Because tariffs established for coal movement reflect the actual costs of transportation as dictated by rail routes, it was possible to calculate transportation charges.

Another constraint imposed on the cost calculations was the assumption that industries could only have one coal pile. Fuel blending is not considered because industrial installations are typically too small to justify blending facilities. As a result, if different stacks in a plant were subject to different regulations (such as would be the case with a sliding scale regulation), the sulfur content selected for the entire plant would be that required by the most stringent of the applicable regulations.

Only the increased fuel costs inherent in switching to lower sulfur content coal were considered in developing costs for this control option. Document 9 presents, on a generalized basis, the potential constraints of burning eastern low-sulfur coals in a variety of non-utility sized boilers. Included in this analysis were single retort underfeed stokers, multiple retort underfeed stokers, and pulverized coal units. The fuel costs may understate

industry costs if coal conversion by these units results in increased expenditures related to capital equipment and operation and maintenance charges.

It should be made clear, however, that the foregoing statement is only generalization. Knowledge of the specifics of individual cases (including the type of stoker, present coal type, present degree of compliance with both particulate and SO_x regulations) could reveal additions to the compliance costs of fuel switching. However, such data was not available for this study and, thus, such considerations could not be taken into account.

No cost calculations were performed for boilers presently burning oil and switching to coal. Data relating to capital charges, and to operating and maintenance costs of converting from oil was not readily available.

3. FGD - Low Sulfur Coal

For fuel combustion stacks where the required reduction exceeded 80%, another control approach was evaluated. This approach substituted a lower sulfur content coal for the existing coal to bring the plant to a SO_x emissions level five times greater than the regulation level (so that the regulation level would then represent one-fifth or 20 percent of the resulting sulfur content). FGD can then be applied to reduce the emissions the remaining 80 percent to meet the regulation level.

The costs of such an approach were determined in two steps paralleling the two phases of the control approach. In the first, the cost algorithm duplicated that described in the foregoing subsection on low sulfur coal substitution. The second step, covering the FGD portion of the reduction, was the same as that described in the discussion on flue gas desulfurization (section II.B.1).

Because the switch from oil to coal was not considered economically feasible for industrial sources, this two-phase control was not considered for oil-burning sources.

4. Low Sulfur Oil

Sources seeking to comply with SO_x regulations also have the option of switching to oil of lower sulfur contents. Costs of this option were evaluated for sources presently burning coal as well as oil.

The costs for switching from one type of oil to another are determined by the differentials in the prices of the oil at different sulfur contents. To calculate the costs, the price differentials incurred in the switch to a lower sulfur oil were taken from Table II-3. The more expensive differential was used. These were multiplied by the plant's energy consumption to yield the deserved cost, assuming 6.2 mmbtu/barrel.

To determine the costs incurred by a plant when it switches from coal to oil, the same basic procedure was followed. The price differentials were determined between the existing coal sulfur content category and the price for the appropriate oil sulfur content category necessary to comply with the regulation.[1/]

C. General Process Sources

The first types of process sources considered were those which burned fuel to heat a process directly. These units have the same central options available to them as do boilers, namely FGD, low sulfur coal, and low sulfur oil. However, the capital and non-fuel O&M costs for converting such processes to oil as well as the precise forms of the FGD cost algorithims as applied to fuel combustion processes were unavailable. Therefore, the only option considered was that of conversion to low sulfur coal.

1. Data Sources

Two different lists of fuel combustion process sources were available for this analysis, one prepared by EPA-Region V in its

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1/ The price of oil used was the price of high-sulfur (2.2%) residual #6, $10.18 (as reported in Platt's OILGRAM Price Service, March 19, 1976, New York Edition) plus the price differential determined above.

efforts to develop SO_2 emission regulations, and the other prepared for the data tape described in Section I.C. The latter list contains many more sources than the former; however, the additional sources contained seem primarily to be:

- incinerators which are exempted from control requirements in both sets of regulations; and
- processes which use natural gas or other types of low sulfur fuels, and hence might be in compliance with either the November, 1975 or August, 1976 form of the regulation.

In addition, due to a variety of data reporting problems, [1/] the accuracy of the data tape information could not be guaranteed. As a result it was decided to employ the source list prepared by EPA Region V.

2. General Cost Approach

Conceptually there are three pieces of information needed to use the cost algorithms described in Section II.B.2 for calculating the costs of compliance incurred by fuel burning processes. First, knowledge of the existing sulfur content of the fuel burned allows the existing price paid for the fuel to be determined. Second, the reduction required by the regulation is necessary to determine the permissible sulfur content and the fuel price increase associated with compliance. Lastly, the annual fuel consumption is needed to determine the net annual cost of such a switch in fuel utilization.

Neither the data tape nor the Region V list of process sources provided any of the three pieces of information described above.

1/ The most important of these problems was the lack of consistency in reporting process weight rates. In some cases these were reported on the basis of total non-fuel input weight, in others as the weight of total outputs, and only in a portion of the total list as the correct total weight of inputs.

Table II-3

Desulfurization Costs of Residual Oil

Desired Sulfur Level(%)	Direct Desulfurization Costs Arabian Light 1974 $/bbl.	Indirect Desulfurization Costs Venezuela 1974 $/bbl.
.2	1.73 - 2.00	1.36
.3	1.60	1.28
.5	1.46	1.15
.7	1.33-1.77	.95
1.0	1.88	.81
1.5	.90	.47
2.0	.69	.13
2.5	.35	.00
3.0	.00	.00

Source: "The Costs of Sulfur Oxide Controls for Oil Burning Power Plants in 1980", report prepared by EEA for U.S. EPA under contract 68-01-1924, Sept., 1975.

Instead, only data on the weight of total inputs fed into the process per hour (process weight rate) and the emission rate (weight of SO_2 discharged per unit time) were available.

To determine the pieces of data needed from that information actually provided requires the development of three factors for each process considered. These include:

- the ratio of fuel use to total process weight input. This value allows a determination of the amount of fuel used to heat a given amount of material fuel into the process.
- the ratio of SO_x emitted to the amount actually contained in the fuel being burned. In several types of processes, chemical reactions with the non-fuel materials neutralize some of the SO_x created when the fuel is burned. With these first two factors (i.e., the fuel use to process weight ratio and the SO_x emitted to SO_x generated ratio), it is possible to determine the sulfur content in $\#SO_2$/ MMBTUs of the existing fuel.
- the capacity utilization of the process. With this value the annual operating hours of the unit in question may be determined. This, in combination with the first factor, allows the calculation of total annual fuel use in the process.

Because the allowable emissions from fuel combustion type processes are expressed in terms of process weight rate in both sets of regulations, the reduction in sulfur content required may easily be calculated from the foregoing information.

3. Derivation of the Factors Used in Process Calculations

Table II-4 presents the factors used in generating process control costs. The sources for which costs were calculated fell into three industrial categories, namely cement kilns, lime kilns, and brick kilns.

For the fourth category, secondary lead smelters, costs were calculated in a different manner. Because SO_2 emissions in these processes stem from sulfur in the input material, rather than in the fuel burned, low sulfur coal is not a means for reducing emissions to allowable levels. In fact, of the control options considered, only FGD may be used.

To determine the costs of installing this equipment the FGD cost algorithms described in Section II.B.1 were used. In applying the formula, it was assumed that the maximum and average firing rates were identical and that they were equal to .3549 tons of coal for each one ton of process weight. The annual operating hours were assumed to be 7687 (product of number of hours/yr and the average capacity utilization for SIC 33 in 1974). Sulfur content was assumed to be 5.1%.[1/]

D. Chemical Sources of SO_x

The only examples of chemical process SO_x emitters in Ohio are sulfuric acid plants. Of these, four plants (5 processes) employ the dry gas method of production and one plant (2 processes) uses the wet-gas method. There is also one zinc smelter in the state which has a wet-gas sulfuric acid plant for the purpose of reducing sulfur dioxide emissions. For more detailed explanations of these processes, the reader is directed to the Document #9.

Dual absorptior was selected as the control technology for reducing the SO_x content of tail gas from sulfuric acid plants

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1/ Based on .4296 ton coal/ton of lead processed (FEA, Voluntary Industrial Energy Report, 1975) 87# SO_2 emitted/ton of lead processed (AP-42).

to acceptable levels. The cost algorithms were dependent on the capacity of the plant in determining the capital and O&M costs associated with this control, but they did not allow for anything but maximum control of emissions. Accordingly, the formulas were modified to allow a certain portion of the tail gas to be by-passed.

The formula for determining how much of the tail gas stream must be treated is given by:

$$\frac{\text{Allowable Emissions at Regulation Level - Uncontrolled Emissions}}{\text{Emissions Assuming No Bypass - Uncontrolled Emission}} = \tau$$

This ratio is multiplied in the cost algorithm by the plant capacity. Thus the general form of the equation used for costing in this analysis was:

$$\text{Cost} = A \times (\tau \times T)^b$$

Assume a plant has uncontrolled emissions of 1300 tons per year, and the regulation allows an emission level of 320 tons per year. If emissions assuming no bypass, i.e., emissions at the maximum degree of control, are 80, the τ ratio would be .8, and therefore, only 80 percent of the tail gas stream would require treatment.

If the τ ratio is negative, resulting from the regulation emission level exceeding the uncontrolled emission level, the plant would comply with the regulation.

The τ ratio is 1.0 or greater when allowable emissions (i.e., regulation level emissions) are less than emissions at the maximum degree of control. In this case, the plant would be incapable of meeting the regulation.

As the τ ratio decreases, (i.e., approaches zero), the costs of compliance, both capital and annual, also decrease.

Table II-5 presents the values of A and b used for determining capital and operating and maintenance costs. Table II-6 shows the values used for controlled and uncontrolled emissions and plant capacity for each of the plants.

E. Oil Refineries and Steel Mills

A final category of industrial SC_x emitters contains those plants which use byproduct gases. The processing of petroleum and coke, in particular, generates large volumes of combustible gas containing some hydrogen sulfide (H_2S). To avoid the odor and potential toxic hazards associated with H_2S and to utilize the heat value of this fuel, these gas streams are burned or flared, which causes the H_2S to be oxidized to SO_2.

The least expensive method of reducing the quantities of these pollutants was determined to be amine stripping of the individual gas streams and regenerating the amine solution in a central facility with a Claus unit to recover the sulfur in its elemental form. However, the cost algorithms for these controls cannot be developed for individual gas streams, and instead are aggregated for the entire plant. Further details are provided in the following subsections.

1. Oil Refineries

Two systems providing different levels of control are evaluated for oil refineries. These are 1) amine scrubbers and strippers with two-stage Claus units for recovering sulfur in the acid gas streams, and 2) the same system with a tail gas unit capable of recovering 99.5% of the total sulfur in the acid gas (equivalent to SCOT Unit).

Table II-4

Factors Used in Compliance
Costs for Processes

Process Type	MMBTU/ # Process Weight Rate	$\#SO_2$ Emitted/ $\#SO_2$ Generated	Capacity Utilization[6/]
Cement Kilns	.0022[1/]	.5[4/]	.79
Lime Kilns	.0017[2/]	.5[4/]	.79
Brick Kilns	.00095[3/]	1.0[5/]	.79

1/ Assumes 1/3 # of coal and 1.6 # of non-fuel inputs needed to generate 1 # of cement output.

2/ Assumes .31 # of coal and 2 # of non-fuel inputs needed to generate 1 # of lime output.

3/ Assumes .083 # of coal and 1.02 # of non-fuel inputs needed to generate 1 # of brick.

4/ Estimates from Document 9.

5/ Estimate from AP-42.

6/ Average of 1974 quarterly capacity utilization rates for SIC 32 calculated by the Division of Business Investment Department of Commerce.

Table II-5

VALUES OF A AND B IN THE EQUATION $C=AT^B$ REPRESENTING INVESTMENT AND OPERATING AND MAINTENANCE COSTS FOR EQUIPPING SULFURIC ACID PLANTS WITH DUAL-ABSORPTION FACILITIES

Type of Sulfuric Acid Plant	Capital Costs		Operating and Maintenance Costs (a)	
	A	B	A	B
Dry Gas	15,404	0.60	2,810	0.71
Wet Gas	97,283	0.61	6,839	0.64

(a) Operating and maintenance costs include operating labor, electricity, cooling water, fuel oil, maintenance, taxes, insurance, and credit for additional sulfuric acid obtained from operation of the dual-absorption facilities.

SOURCE: Document 9.

Table II-6

Values for Key Parameters
In Sulfuric Acid Plants

Ohio ID	Stack #	Name	Plant Capacity (tons/day)	Emissions Assuming no by-pass (tons/yr)	Uncontrolled Emissions (tons/yr)
18000151	5	Dupont	1000	667	1893
18222594 (1&2)	1	Allied Chemical Corp.	400	82	1282
18222594 (2)	1	Allied Chemical Corp.	200	41	641
25040002	3	American Smelting & Refining Co.	192	275	728
31350817	1	Dupont-Fort Hill	600	765	2435
48020014	3	Coulton Chemical Corp.	324	372	1455
48020014 (2)	4	Coulton Chemical Corp.	216	214	228
77040002	1	Three-M Company	180	172	734

For both SO_x emission regulations costed, it is assumed that the general sulfur recovery plant standard will not apply to oil refineries. Though the August, 1976 standards are clear on this point, there is some ambiguity in the November, 1975 regulation. In this regulation, if the Claus plant is primarily for abatement, no tail gas cleanup is required; however, only coke oven gas is specifically exempted.

The cost algorithms in Document #9 for oil refineries assume that the maximum degree of control for oil refineries. To tailor these formulas to the specific SO_x removal requirements of individual plants, a factor (B) was developed which represented the amount of gas stream which had to be treated. The equation for the bypass factor was given as:

$$\beta = \frac{\text{Emissions at Reg Level (tons/yr)} - \text{Uncontrolled Emissions (tons/yr)}}{\text{Emissions Assuming No. Bypass (tons/yr)} - \text{Uncontrolled Emissions (tons/yr)}}$$

If a two stage Claus unit is capable of meeting the regulation, the value used for emission at maximum control reflected a 94 percent removal efficiency. If a Claus unit is insufficient for compliance, tail gas treatment was assumed, and the removal efficiency was changed to 99.5 percent.

Table II-7 shows the formulas used for each of the control units. If only a two-stage Claus unit is necessary, then the entire control costs would be given by the sum of the amine scrubbing and stripping and the two stage Claus costs. If a tail gas unit

was required in addition, the total price would also include this cost component. Table II-8 shows the values of key parameters for six of seven refineries in Ohio.

For one refinery, the Toledo facility operated by Gulf Oil, costing proved more difficult than the foregoing procedures, because a portion of its fuel gas streams are now partially treated, while the remaining portion are presently uncontrolled. For the purposes of this analysis it was assumed that two gas streams had to meet the regulation. First was the stream which was presently being treated by amine scrubber/stripper and Claus unit. The second was the stream which received no treatment. For the latter stream, an appropriately-sized scrubber/stripper together with one two-stage Claus plant of 100% of needed capacity and a tail gas unit were costed. The amount of the first stream's Claus plant tail gas needing treatment to insure compliance with the regulation was then assumed to be also added to the tail gas unit under consideration for the uncontrolled stream. The additional increases in size of this unit were then taken into account. Figure 2-1 is a schematic diagram of this assumed configuration, with the values of key parameters specified.

2. Steel Mills

Coke oven gas burned in steel mills must also be controlled. One central system was found to be capable of achieving the reduction levels necessary, namely an amine scrubber/stripper system with an attached two-stage Claus unit. Both the November, 1975 and August, 1976 regulations specifically exempt Claus units treating coke oven gas from sulfur recovery plant emission standards which migh require the addition of a tail gas unit.

The cost algorithms in Document #9 were modified in two ways. First, a credit for sulfur recovered from the Claus units was included, assuming a $20/long ton price for each ton of sulfur recovered. Secondly, a factor was included to reflect the capability of a plant to tailor its control system to meet its specific regulation level. This factor was determined by the general equation:

$$T = \frac{\text{Emissions at Regulation Level (tons/yr)} - \text{Uncontrolled Emissions (tons/yr)}}{\text{Emissions assuming 13\% removal of sulfur in fuel gas (tons/yr)} - \text{Uncontrolled Emissions (tons/yr)}}$$

Table II-9 shows the capital and O&M formulas used in the analysis. Table II-10 lists the values assumed for the key parameters in these equations.

Table II-7

Cost Algorithms Used
For Costing Oil Refinery SO_2 Controls

Control Unit	Capital Cost	O&M Cost
Amine Scrubber and Stripper	$749(*Barrels/Day Capacity)^{.07}$	.07(Capital Cost + (Yearly sulfur inputs to Claus Unit) 36.66
Two Stage Claus Unit	$\$150,000(LTS)^{0.627}$	.05(Capital Cost) + $2.78*(LTS/Year) sulfur credit ($25) - $25* Efficiency of Claus Unit LTS/Year - $1.41 Efficiency of Claus Unit LTS/Year
Tail-Gas Unit (where necessary)	$\$102,000(LTS)^{0.584}$	$2.76*LTS/Year

LTS = Sulfur input to Claus Unit in long tons = *(weight of sulfur in uncontrolled emissions).

Efficiency of Claus Units = 94.5%

Table II-8

Values for Key Parameters in

Oil Refinery Equations

Ohio ID	Name	Capacity (barrels/day)	Uncontrolled Emissions (tons/yr)	Annual Fuel Gas Consumption (MMSCF/Year)
31080082	Gulf Oil - Cleves	43,500	969	6,179
48010060	Gulf Oil - Toledo	31,016	1,944	2,547
48020007	Standard Oil of Ohio - Toledo	126,000	9,801	7,354
02020012	Standard Oil of Ohio - Lima	177,000	693	14,800
32010020	Ashland Oil - Findlay	21,000	236	108
76000301	Ashland Oil - Canton	66,000	174	4,446
48010246	Sun Oil	130,000	9,191	16,747

Table II-9

Cost Algorithms
Used For
Costing Steel Mill
Coke Oven Gas Controls

	Capital Cost	O&M Cost
Coke Oven Gas Control Unit (includes amine scrubber/stripper and Claus unit)	$.71(Y)^{.56}$	$\frac{Y - .46}{72.37}$ Annual Sulfur Recovered $20/long ton

Y = daily capacity of coke oven gas (MMCF/D)

Table II-10

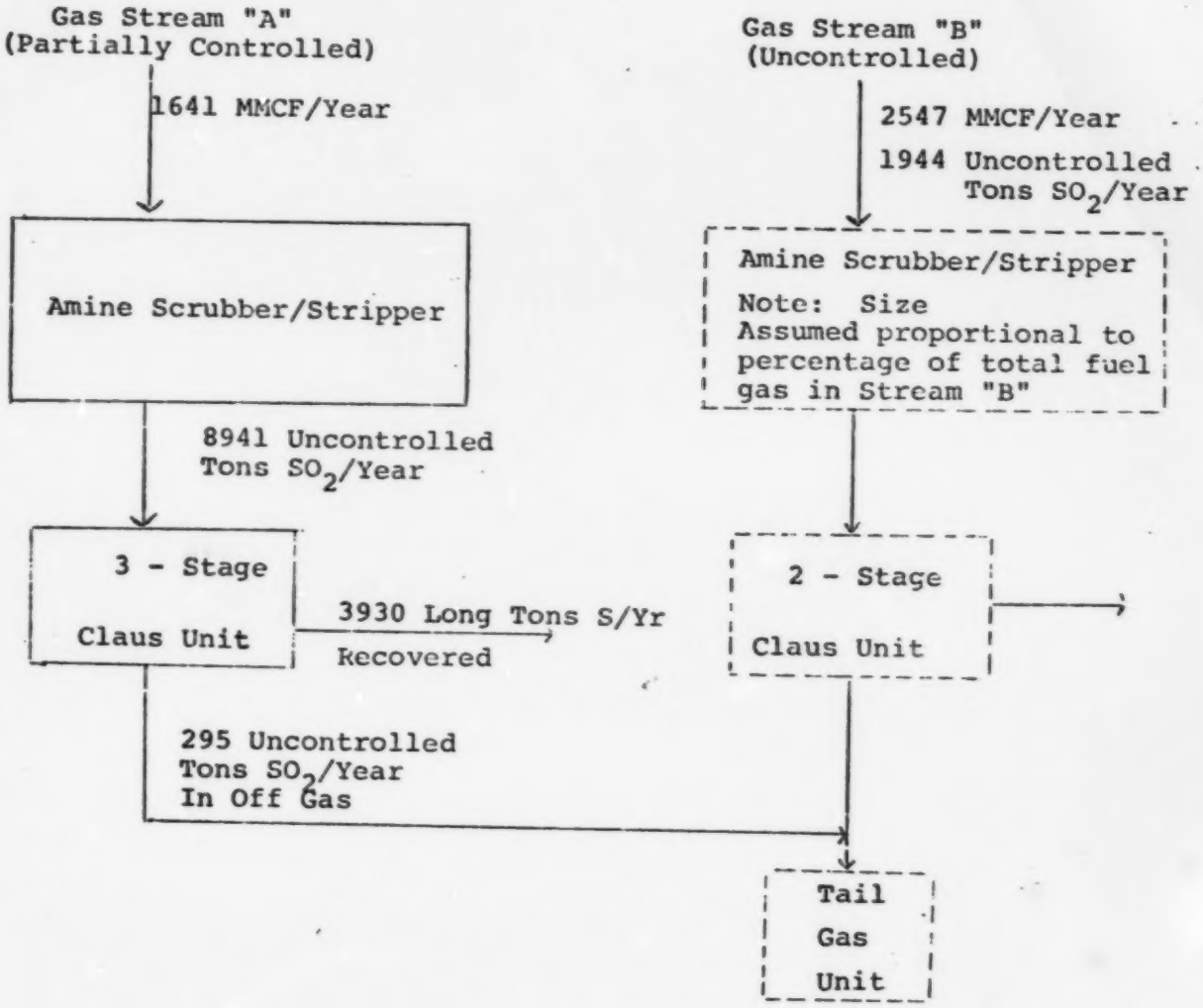
Values of Key Parameters

in Steel Mill Equations

Ohio ID	Name	Daily Coke Oven Gas Capacity (MMCF/D)	Uncontrolled Emissions (tons/yr)	Controlled Emissions (tons/yr)
48010397	Interlake Inc.	12.31	596.00	42.00
44010004	Ironton Coke Plant - Allied Chemicals	37.00274	9222.00	644.00
50090241	Campbell - Youngstown Sheet & Tube	37.42	6408.00	449.00
73010004	Empire Detroit Steel	11.616438	1993.00	140.00
47080049	U.S. Steel - Lorain / Cuyahoga	47.567123	5629.00	394.00
18001613	Republic Steel Corp.	57.21	6045.00	423.00
78080337	Republic Steel Corp	13.94	1902.00	133.00
09080023	Armco Steel - Hamilton	17.273973	2044.00	143.00
09010006	Armco Steel Corp. - Middletown	15.030137	1778.00	124.00
50110464	Republic Steel Corp.	32.23	2871.00	201.00
76130696	Republic Steel Corp.	6.85	472.00	33.00

Figure 2-1

Schematic Diagram
Of Fuel Gas
Streams In
Gulf Oil's Toledo
Refinery



Capacity = 51,000 Barrels

Dotted Lines represent controls under consideration;
Solid lines represent controls already in place.

APPENDIX A

INFLATION IMPACT STUDY DOCUMENTATION

This appendix identifies the documents prepared to support the Inflation Impact Analysis of the sulfur oxide regulations prepared by the U.S. Environmental Protection Agency (EPA) for the state of Ohio.

Figure 1 identifies the supporting documents. Document #2 provides an overview of the study methodology and illustrates the depth of analysis contained in the study.

Impact Studies

Documents #3 and 4 are economic impact analyses of the utility and industrial sectors in Ohio. These reports address impacts on prices, output, employment and financial viability. Document #5 summarizes the energy impacts of the regulation in terms of the level of energy demand, shifts from coal to oil likely to occur as a result of compliance with the regulations as well as shifts in coal production patterns. In particular, this report focuses on whether coal production in Ohio, which is generally high in sulfur content, will be adversely impacted.

Cost Minimization

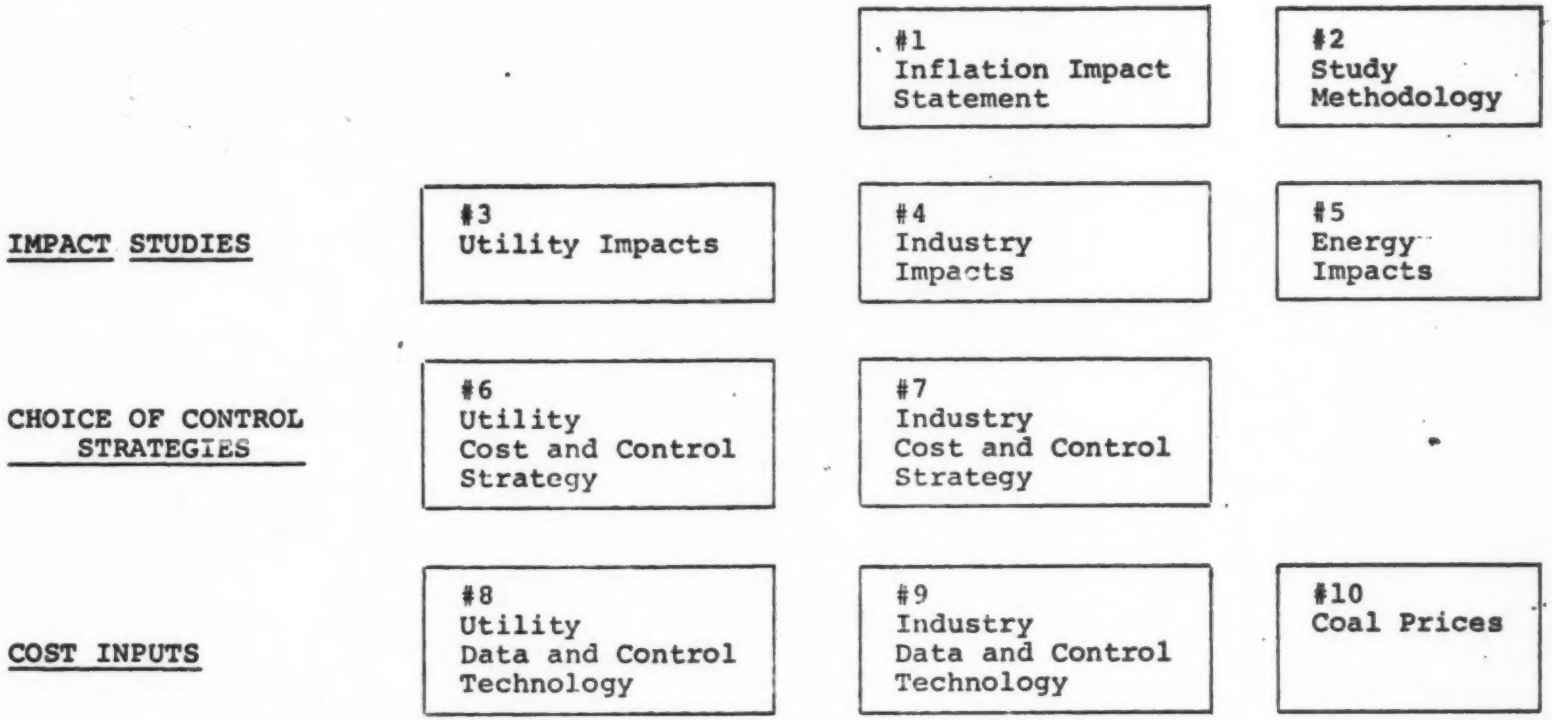
Documents #6 and 7 present the methodology for estimating costs of compliance and the choice of pollution control strategies. For both utility and industry, these supporting documents outline the cost minimizing strategies which provide the basis for the economic and energy impacts discussed in documents #3 - 5.

Cost Inputs

These final documents contain the basic data inputs to the study. Document #8 describes the pollution control technology options, their costs plus basic plant specific parameters which influence costs such as fuel consumption and boiler firing rates.

Figure 1

INFLATION IMPACT STATEMENTS SUPPORTING DOCUMENTS



Document #9 contains similar data on the industrial sector. Document #10 presents the derivation of coal prices employed in this study and used in both the industry and utility sector analysis. The focus is on the price premium of low versus high sulfur coal.